FY2003 EPA REGION 6 END-OF-YEAR EVALUATION OF THE RAILROAD COMMISSION OF TEXAS (RRC) UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

(September 1, 2002 - August 31, 2003)

Introduction

The Railroad Commission of Texas regulates Class II, Class III brine mining, and energy related Class V injection wells for the State of Texas. The Environmental Protection Agency (EPA) delegated primacy for those wells to the RRC effective May 23, 1982. The RRC's primacy revision package for the Class III brine mining program was approved by the EPA Administrator on February 9, 2004, published in the Federal Register on February 26, 2004, (Vol.. 26, Num. 38, pages 8824 - 8828) and effective March 29, 2004. The UIC program is currently administered within the RRC by Environmental Services (ES) of the Oil and Gas Division. This report summarizes the activities reported by ES to fulfill grant, and workplan commitments and discusses information collected by EPA throughout the year through field inspections, file reviews, and office visits.

Section 1 FY2003 Grant Work Plan

In exchange for the federal assistance, ES provided Region 6 with a grant application and proposed workplan outlining goals, expected milestones for key programmatic activities and estimated funding for achieving those milestones. Comments were provided by EPA and on August 29, 2002, ES submitted amendments to the grant application and workplan for FY 2003 that were subsequently approved.

Subsection 1.1 FY2003 Grant Award and Allocation

On April 24, 2002, the initial Federal FY 2003 allotment for funding the RRC's UIC program's regular programmatic activities was set at $661,200, approximately $8,600 less than in FY 2002. On September 11, 2002, the RRC was awarded $18,700 of FY 2002 funds to purchase 20 radiation survey instruments. In addition to those funds, on May 20, 2003, the RRC was awarded $658,400 for regular programmatic activities bringing the total federal funding for FY2003 to $677,100.

Subsection 1.2 Grant Deliverables

Table 1.2 reflects the RRC's compliance towards delivering to Region 6 key items listed within the annual workplan. All deliverables were received in a timely fashion with the exceptions of the quality management plan and final financial status report.

Table 1.2

Grant Deliverable	Due Date	Date Received
Quality Management Plan/Project Plan Updates [1]	April 1, 2003	April 10, 2003
Quarterly Reports Office of Management and Budget (OMB) Forms 7520	October 31, 2002 January 30, 2003 April 30, 2003 July 30, 2003	November 4, 2002 January 14, 2003 No record of receipt July 7, 2003
Annual UIC Narrative Report [2]	November 15, 2003	November 7, 2003
Final Financial Status Report [3]	September 30, 2003	January 21, 2004
UIC Annual Inventory	December 31, 2002	January 15, 2003

1 This date is set 1 year from date of last approval. Administrative grant condition #10 requires a Quality Assurance Project Plan (QAPP) before data collection starts.

2 During FY2001 the annual narrative due date was renegotiated to November 15 each year beginning in FY2002.

3 Administrative grant condition #5 requires the financial status report 90 days after the budget period.

Section 2 Inventory 2003

Table 2 identifies the number of injection wells per well class as reported at the beginning of calendar year 2003. The RRC UIC program ranks as the largest UIC program in the nation based on the total number of Class II wells on inventory.

Table 2

Well Class	Types Included	Inventory
II	Saltwater Disposal, Enhanced Recovery, Hydrocarbon (HC) Storage	51,295
III	Brine Mining	93[1]
V	Other wells	6

1 The 93 Class III wells are located within 77 sites.

Section 3 Key Programmatic Activities Between September 1, 2002 - August 31, 2003

The RRC UIC program met or exceeded nearly all workplan projections for FY2003. The tables and charts in Sections 3.1 - 3.5 summarize key programmatic activities, as reported in the annual narrative, and compare them to workplan projections. In addition, for purposes of developing trend analysis, equivalent FY2002 data is provided

Subsection 3.1 (A) Mechanical Integrity

Table 3.1 (A) depicts a comparison of mechanical integrity testing activities (MITs)between FY2002 and FY2003 and how well the RRC accomplished their workplan projections for those two years.

Table 3.1 (A)

Activity	Accomplished		Workplan Projections		Percent of Projection Achieved	
	2002	2003	2002	2003	2002	2003
Wells tested using mechanical integrity pressure tests (MIPT)	16,369[1]	15,511[1]	14,000	14,500	>100%	>100%
Number of MIPTs witnessed and received in Austin	2,835[2]	3,418[2]	10% or greater	2,500	17% of all wells tested	22% of all wells tested
Number of radioactive tracer surveys or temperature surveys conducted	99	91	80	100	>100%	91%
Number of HC Storage wells tested	96	87	100	100	96%	87%
Class III brine mining wells tested	48[3]	67	75	75	64%	89%

1 This number represents the total number of well test reports received in the Austin office. The narratives did not identify how many of these tests are failures. **Because the number of MIT failures discovered are of key importance, EPA again requests this information be provided in future narratives.**

2 This number represents the total number of witnessed well tests reports received in Austin and is discussed in greater detail in Section 3.1 (b) below.

3 The rate of accomplished MITs for Class III brine mining wells over the past two years 64% and 89% respectively, does not meet the RRC requirement of an annual demonstration of mechanical integrity for each well. However, the applicable federal requirement, once every five years, can be easily exceeded at the current test rate.

Subsection 3.1 (B) MIT Reporting by Operators

Table 3.1.(B) reflects the change in status over the last two years of the ongoing issue with witnessed MITs not being submitted by operators to the Austin office. It is believed failed tests account for the majority of tests not submitted. Non-reporting of tests

increased from FY2002 to FY2003 with 1/4 of all witnessed tests not being reported for FY2003. The RRC has used outreach seminars to inform operators of the requirement to report all MITs conducted. The RRC is commended for witnessing 22% of those tests reported to Austin.

Table 3.1 (B)

Activity	Witnessed MITs submitted to Austin		Witnessed MITs reported by District Offices		Percent of total reported by Districts received in Austin	
	2002	**2003**	**2002**	**2003**	**2002**	**2003**
Witnessed mechanical integrity pressure tests (MIPT)	2,835	3,418	3,366	4,648	84%	74%

Subsection 3.2 Permitting

In FY2003 the RRC projected they would receive and process approximately 1000 permit applications covering an estimated 1850 wells. The activities reported in Table 3.2 reflect a slightly reduced workload was addressed in 2003 from 2002. Of note, the RRC reports no applications received for fluid injection projects or area of review variances.

Table 3.2

Activity			Accomplished					
	Applications received		Permits issued[1]		No. of wells in applications		Permitted No. of Wells	
	2002	2003	2002	2003	2002	2003	2002	2003
Class II SWD and ER permits	1037	948	892	810	1992	1892	1834	1550
No. of Hydrocarbon Storage facilities	1	1	4	0	----[3]	29	8	0[2]
No. of Class III brine mining permits applications received	5	20	2	8	7	20	----	8
Salt Cavern disposal wells	----	2	----	2	----	----	----	2

1 Of the combined 820 permits issued, 26 applications required resolution by public hearing
2 One HC storage well permit amendment is currently under review.
3 "----" is inputted into the table when no data is available

Subsection 3.3 Permit Compliance Reviews/Inspections

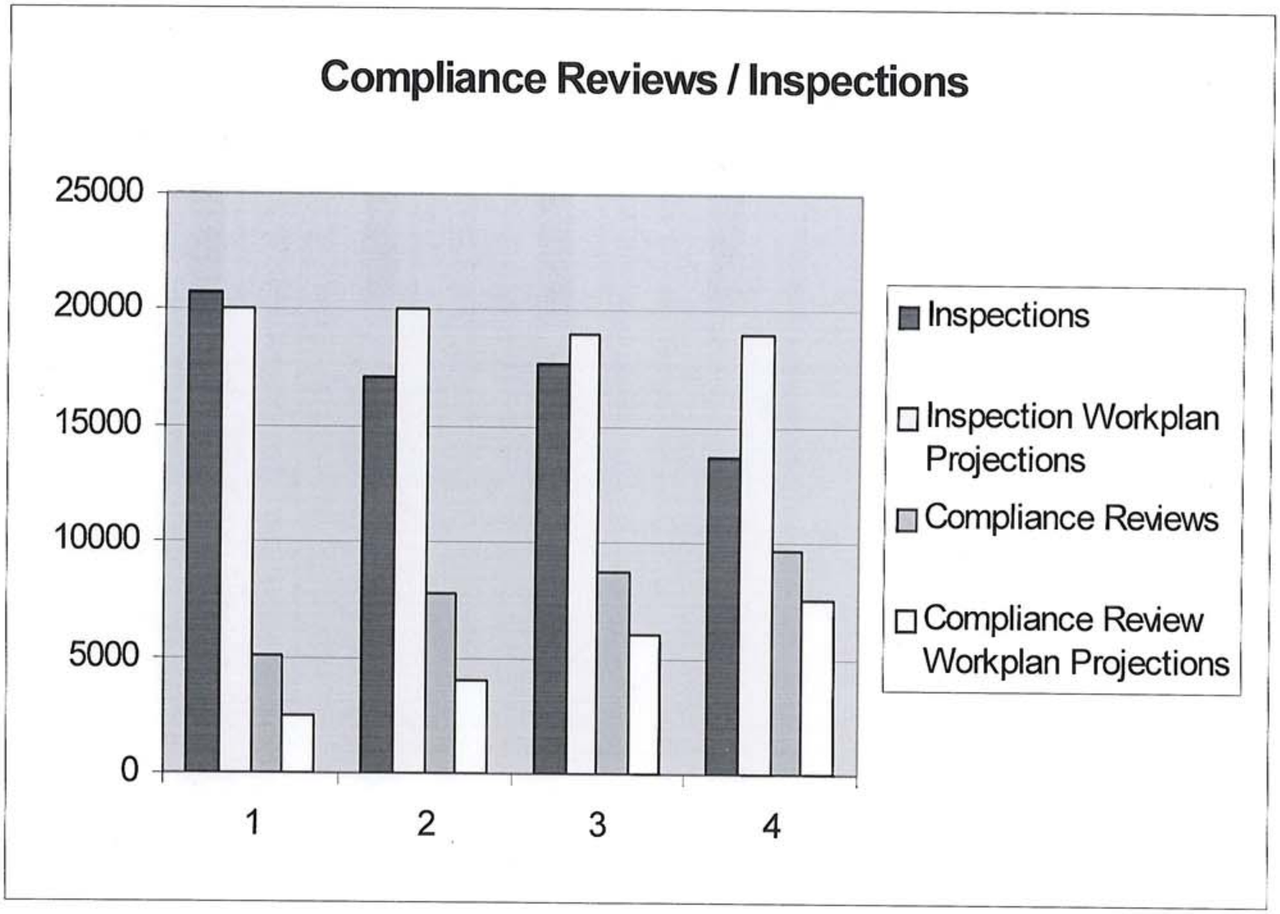
This year the number of permit compliance reviews exceeded workplan projections by 2223 reviews. The RRC's commendable effort resulted in an increased number of identified violations and subsequent enforcement actions. Compliance reviews are enacted upon permit amendment, change to commercial status, new completion report received, requests by field operations, operator name change, citizen's complaint, request for a technical exception, the annual report indicates problems, a new pressure test is received, and when other special circumstances occur.

Chart 3.3 reflects 4-year trends for compliance reviews and inspections conducted by the RRC. Compliance reviews have steadily increased, nearly doubling over the past four years. The total number of inspections have fallen from 20,700 in 1999 to 13,716 in 2003, roughly 66% of the level of effort 4 years ago or 26% of inventory. Although overall inspection activity has dropped, inspections to witness MIPTs during the State's fiscal year is up to 22% (Table 3.1 A) and near EPA's recommended rate of 25%.

Chart 3.3

Subsection 3.4 Annual Operator Reporting

A primary mechanism to track the injection activities of the regulated community is



through the collection of the annual report. Required for each individual well, operators report the monthly volumes injected, the maximum and average injection pressures utilized and (optionally) annulus monitoring results. Operators are encouraged to report electronically. The RRC has consistently and aggressively collected and evaluated these forms for compliance purposes. For those wells not directly inspected in the field, the report provides the primary means for annually determining a well's operational status. Table 3.4 reflects the status of the RRC's collection efforts for these reports for disposal and enhanced recovery wells (H-10) and hydrocarbon storage wells (H-10H) for FY2002 and FY2003 respectively.

Table 3.4

Activity		Reported		Projected		Percent of Wells on Inventory[2]	
		2002	2003	2002	2003	2002	2003
Annual Reports	H-10	45,983	45,800	47,000	46,000	91%	91%
	H-10H	742[1]	611[1]	520[1]	520[1]	100%	100%

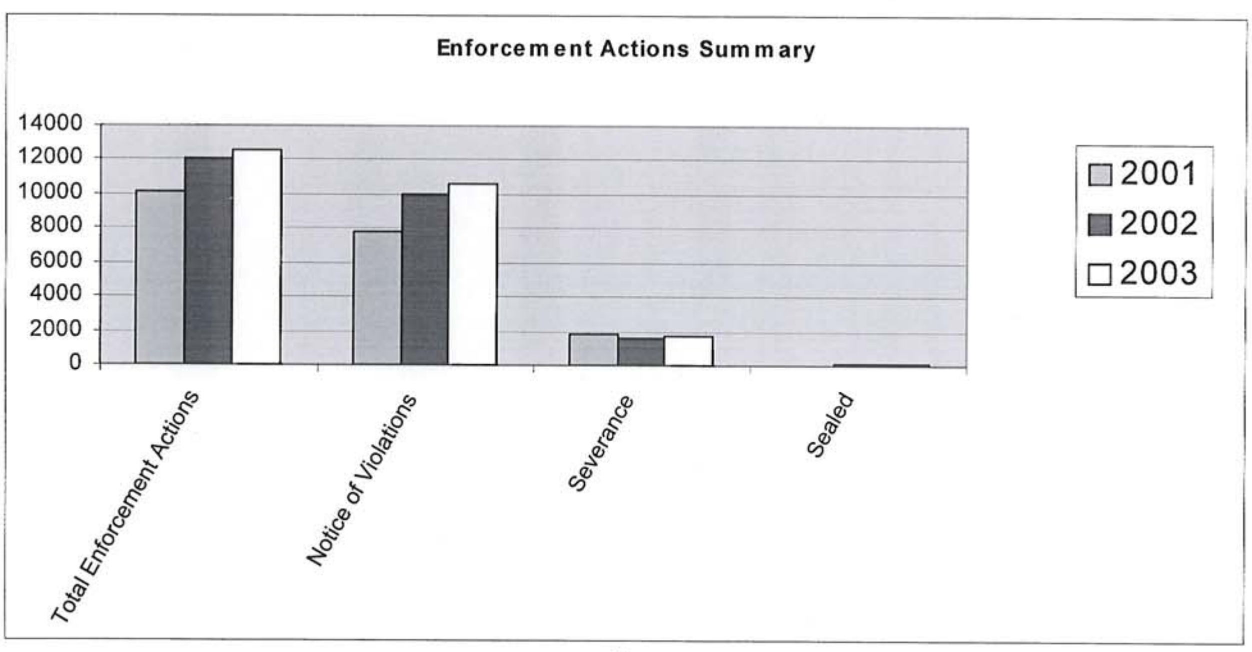
1 Annual reports are submitted on every hydrocarbon storage well. The projection 520 reflects the near inventory and thus the number of wells expected to file a report. The significantly higher number of reports reported as opposed to projected is explained as largely the result of multiple submissions received on a single well. If an error is perceived in an original submission, the form is returned, corrected and resubmitted. Under the RRC's tabulation scheme for H-10Hs, this would result in receiving two reports. This method of tabulating the forms reflects the RRC's actual workload. The significant reduction in numbers reported between 2002 and 2003 indicate fewer corrections are being required.

2 Estimated inventory of Class II SWD and ER wells used to calculate percentages for both years is 50,500. This indicates roughly 9 % of wells on inventory or 4600 wells had not complied with the annual report requirement at end of FY2003. This is well within the numbers reported under enforcement actions discussed in Section 3.5.

Subsection 3.5 Enforcement

Chart 3.5 summarizes the enforcement activity taken by the RRC for the past three years as reported in the annual report. By far the largest portion of these enforcement actions are notices of violation (NOV) issued for delinquent annual H-10 reports, followed by delinquent MIT reports. Other less used but effective forms of enforcement include 1533 production lease severances and 78 wells sealed in FY 2003.

Chart 3.5

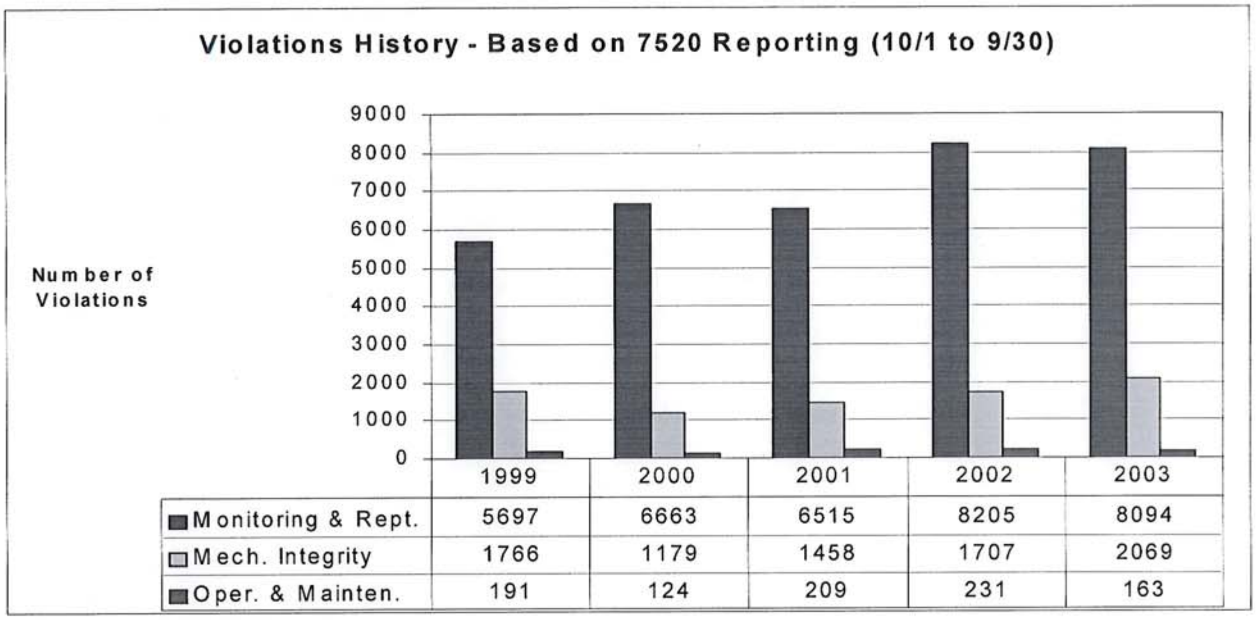


Subsection 3.6 Violation Trends

Chart 3.6, constructed from information reported on OMB Form 7520, reflects a 5-year trend on violations of key RRC UIC program requirements. Consistent with the state's annual report, reporting violations comprise the bulk of the enforcement actions (see Subsection 3.5). Chart 3.6 shows monitoring and reporting violations consistently comprise the bulk of violations annually and a upward trend in MI violations for the past four years. This may be attributed to more MITs being conducted and more of those tests being witnessed (see Subsection 3.7).

Chart 3.6

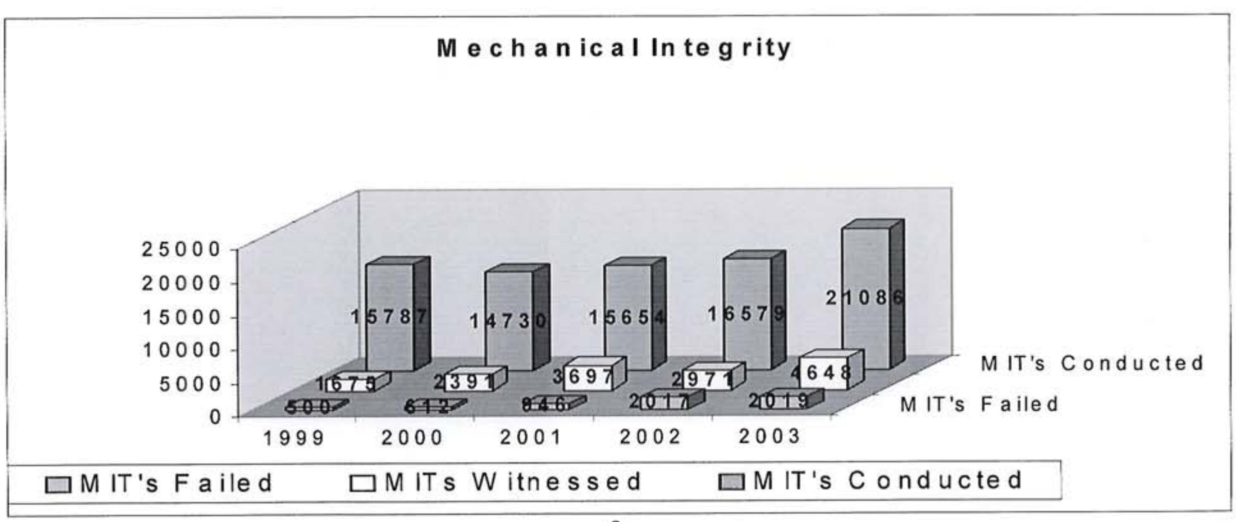
Subsection 3.7 MIT Witnessing



	1999	2000	2001	2002	2003
Monitoring & Rept.	5697	6663	6515	8205	8094
Mech. Integrity	1766	1179	1458	1707	2069
Oper. & Mainten.	191	124	209	231	163

EPA recommends a minimum 25% MIT witnessing rate for an effective program (May 19, 1981; Federal Register Vol. 46, page 27337). From 1998 to 2001, the RRC steadily increased the percentage of witnessed MITs for all tests conducted. From 2001 to 2002 that number fell 20% from 3697 tests to 2971 tests witnessed, or approximately 18% of all tests conducted. In 2003 the number of tests reported witnessed on OMB Form 7520 has increased to 4648, but due to a significant increase in the number of MITs conducted, the overall percentage of MITs witnessed stayed level at 22%.

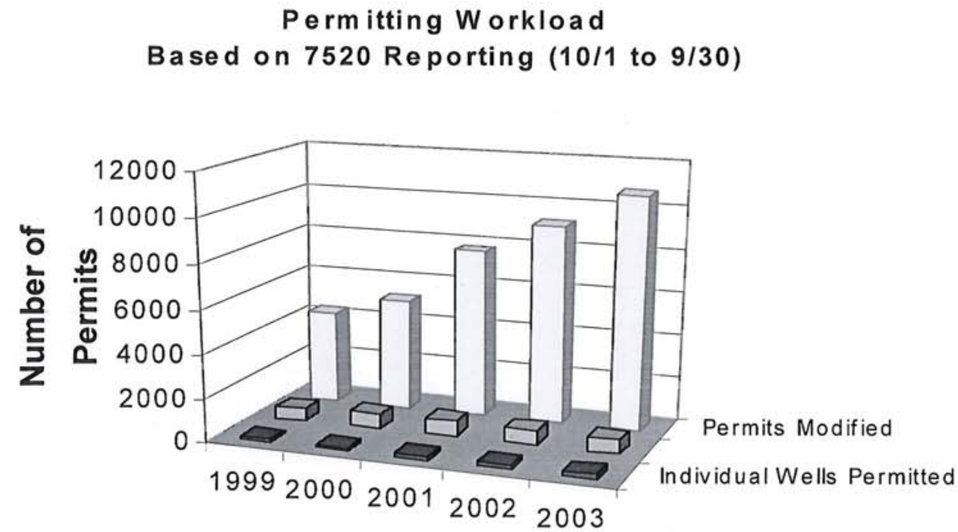
Chart 3.7



Subsection 3.8 Permitting Activity

The RRC reports permitting activities on OMB Form 7520 which categorizes permitting into three activities; permits for individual wells, area permits, and permit modifications. There is not an exact correlation on area permits. Generally recognized as covering all injection in a specific area, the RRC reports permits issued for multiple wells in that category as well. Chart 3.8 shows a 5-year trend on these three activities.

Chart 3.8



	1999	2000	2001	2002	2003
Permits Modified	4274	5129	7761	9133	10700
Area Permits Issued	545	670	724	671	629
Individual Wells Permitted	144	135	175	207	205

The most significant trend from Chart 3.8 is the increasing proportion of permit modifications to permits issued, the number of modifications having doubled in 4 years. In 2003 nearly 20% of the injection well inventory received permit modifications. The number of modifications reported by the RRC include both permit modifications and permit amendments. Modifications are generally initiated by the Commission for purposes of achieving compliance initiated through an enforcement action. Amendments are generally voluntary and initiated by operators. The majority (>90%) of modifications reported are believed to be the end result of annual report reviews that revealed non-compliance with either injection rate or injection pressure requirements, or both. Upon discovery of non-compliance, the RRC will issue a warning letter telling the operator to either come into compliance with existing requirements or amend their permits. Many opt to amend their permits. The RRC's increasing ability to quickly review annual reports and act upon that review is due to steadily increasing data quality and management. The increasing trend in permit modification is a result.

The permit modification trend is also indicative of existing permit conditions for rate and injection pressure becoming increasingly insufficient. Given the need to maintain conditions to economically operate production wells, the necessity to increase rate and/or pressure is indicative of increasing demands in the operational conditions of these wells. Conditions that require additional pressures and volumes may be economic, physical, or both. The economics of diminishing returns, a natural and well documented consequence of mature oil fields, in addition to the natural increase in physical resistance to continued injection into finite reservoirs, provide a logical basis to explain the need for the permit modification trend visible in Chart 3.8.

Section 4 File Reviews

During FY2003, file reviews were conducted by Region 6 at the RRC's Austin offices with follow up at district offices and site inspection of the wells themselves. On the initial file trip in May, twelve H-5 MIT forms were picked at random from one district office for review. No issues were found with the data provided or findings of the reviewers for each test. Of the 12 reviewed, all had passed and 2 had been witnessed. As required, all tests conducted without an RRC inspector present included a pressure chart with tubing/casing annulus pressures recorded. Tubing pressures are logged onto the form, as are casing pressures, but are not required to be documented by a pressure recording as are casing pressures. Reviewers must rely on one source, the completion report, to verify tubing/casing differential pressures are maintained.

Permit files were selected for review from recently issued permits. Lists were made of all documentation found within the files, copies of the documentation were made where applicable, and notes were made of items of significant interest with the intent to verify compliance in the field as follow up. Below are items of interest found within specific file reviews.

RUWCO Oil and Gas Corp., Project No. F16292, Well No. 2, Castena Lease (36577), Stonewall County

The permit, issued May 6, 2003, amended the interval, injection pressure, and volume authorized in a permit issued in January 2003. Both permits, authorizing injection into a reservoir productive of oil and gas, required a cement squeeze prior to operation. No issues were found with the technical reasoning, as applied under RRC policy, for issuing the permit. It is noted that the public notice for the amendment, published in the local paper on February 26, 2003, contains the standard 15-day notice for comment and instructions on how to seek additional information from the RRC. The application, initially received by the RRC on February 27, 2003, was not available to be disseminated for the 15-days indicated by the notice. From this process, should a person with standing inquire during the 15 day period announced in the notice, the RRC would have no prior knowledge of the pending application. In contrast, federal requirements for public notice of draft permits require a complete application be available for review prior to notice. In this review, the application was not deemed complete until April 25, 2003. It should also be noted that the RRC's UIC program need not adhere to or meet these specific federal requirements.

In a field trip in September 2003, records on Well No. 2 were reviewed by EPA at the RRC's district office to verify compliance with the cement squeeze and as follow up to the permit file review. A May 29, 2003, inspection report indicates a successful MIT and compliance with casing and cementing; however, no record of a well construction report (Form W-2) was available at the Midland office at the time of the field visit. Remoteness of the well and time prohibited site inspection.

Pryor Petroleum Corp., Project No. F16356, Well No. 3, Albritton Lease (29110), Stonewall County

The permit, issued May 5, 2003, authorizes injection into a reservoir productive of oil and gas. No issues were found with the technical reasoning, as applied under RRC policy, for issuing the permit. It is notable that the applicant provided pressure front calculations as part of the initial application. Area of review data revealed a questionably plugged well bore approximately 1000 feet from the proposed injector. The calculations, determined using an equation applicable to infinite and unbounded reservoirs, estimated the pressure build up at a well 1000 feet away from the injector would pose no potential harm to fresh water for 20 years. The RRC requested a cross section of the receiving formation to ascertain the applicability of the use of the equation. It was found acceptable. To confirm nonendangerment, the pressure front calculation factors provided in the applications were run on an equivalent model at Region 6 with similar results.

This well was field inspected on September 23, 2003. Upon arrival we found the well with capped tubing and connected for gravity flow annular injection. A poly flow line was connected from the tank battery to the wellhead. The valve at the well was open. The valve at the battery was closed. The well was not actively injecting at time of inspection. The well was permitted for injection through tubing and packer into the interval between 2640' and 2662'. There appears to be potential for multiple violations of the permit including injection without mechanical integrity. As additional evidence that injection may have occurred, an echo meter survey of the packerless annulus shows the fluid level at the time of inspection to exist at about 600' subsurface. The fluid level measured using an Echo Meter appears to be significantly higher than that reported in the permit application on March 27, 2003. The application indicates, at that time, the fluid level existed 444' above the perforations, or roughly 2200' subsurface.

LCS Production Co., Permit No. 11739, Well No. 5D, Funderburk Lease (28976), Stephens County

The permit, issued March 7, 2003, authorizes disposal of non-hazardous oil and gas wastes by injection into a formation non-productive of oil and gas. No issues were found with the technical reasoning for issuing the permit. Notice was again published and complete before the application was submitted to the RRC. On September 25, 2003, a search of the field office records on 5D revealed correspondence warning the operator to seek the proper exceptions to the rules regarding surface casing requirements. The operator had constructed wells in the past, setting surface casing deeper than authorized. As explained, operators will desire to set deeper surface for the additional control it affords blowout preventers. Consequently, setting deeper surface casing, without the appropriate modification to the cementing program, will not result in the placement of the highest quality cement across the base of useable quality water. The RRC has determined that this generally occurs across the bottom 20% of the surface casing string.

A site inspection revealed the well had not yet been converted to an injector and still contained sucker rods. Opening a valve on the tubing string demonstrated liquid was at surface with significant pressure. In addition, the tubing/casing annulus demonstrated significant and sustained gas pressure when the valve was partially opened for nearly 5 minutes. Both valves were closed with no fluid level measurements taken. The well's construction, taken from the latest W-2, indicates the tubing string, which is set with packer at 4331', is exposed to its former production interval at 4448' to 4471' subsurface. The significant and sustained gas pressure in the annulus indicates communication, possibly through the tubing and/or packer. The permit, if enacted, requires the production zone be squeezed and a deeper interval between 4520' and 4648' be opened for injection. No wells exist in the 1/4 mile AOR and only 2 inactive wells are within ½ mile. The significant and sustained pressures evident at the surface warrants consideration of an expanded AOR.

Key Energy Services Inc., Permit No. 05327, Well No. 1D, Alma Brown Lease (18935), Dawson County

The permit, for commercial injection, issued May 7, 2003, amends a permit issued in April 1965. It amends the injection interval, volume, injection pressure, and allows for a packer depth exception. Information in the file reveals that the application to amend was the result of a review of Commission records that revealed the well had been injecting volumes well beyond the original permitted parameters of 53 barrels per day since at least 1990. The permit was subsequently amended in May 2003 to 5000 bbls/day. The historical excessive injection initially made this well a candidate for field inspection, focusing on potential area of review (AOR) concerns. Upon visiting the site, no wells were found within the 1/4 mile AOR that would allow for receiving formation pressure measurement. An abandoned producer, believed to be open to the injection zone approximately one mile from the injection well was used to measure pressures. Echo meter results placed the fluid level near 2500 feet subsurface. If the abandoned producer is hydraulically connected to the injection well's injection interval (3749' - 7304'), pressure influence is not a likely concern. Publication of notice for the amendment did occur after the RRC received the initial application but prior to a complete application.

West Fork Tank Trucks, Permit No. 11743, Johnnie Smith "A" Lease (23741), Well No. 1, Wise County

The permit, issued March 27, 2003, authorizes disposal of non-hazardous oil and gas wastes by injection into a formation non-productive of oil and gas. No issues were found with the technical reasoning for issuing the permit. Records reflect that the RRC recognized the application as one for a commercial disposal well and informed the applicant of specific provisions to be included in commercial disposal well permits. The permit does not reflect these provisions. The permit requires the well's intermediate casing be pulled and new casing set to specifications prior to injection. Records at the district office indicate that all permit conditions regarding construction of the well were accomplished. Site inspection revealed the well operating within permit requirements and as a commercial well.

Section 5 Notable Events

Subsection 5.1 ES Reorganization

ES underwent some internal reorganization in 2003 affecting the UIC program. The Underground Storage and Brine Mining Section was combined with the Disposal and Injection Well Permitting Section to form the Underground Injection and Storage Permitting Section. As a result of this reorganization, ES now provides two sections to perform the functions of permitting and compliance for the UIC program.

Subsection 5.2 Coffman Tank Truck, Kenneth Brunson Lease (30152), Well No. SWD-1, Wise County

Informed that the well had experienced breakouts to the surface, Coffman Tank Truck Well No. SWD-1 was added as a file review during the field inspection phase of this year's file reviews. The Coffman Tank Truck commercial facility was permitted July 2, 2003, for disposal of 14,400 bbls of oil and gas wastes per day into the interval from 2160' to 2250' subsurface. After approximately 3 weeks of injection, the facility experienced two breakouts and apparently caused pressures to build up in the bradenhead of a third. At the time of inspection on September 26, 2003, the well was back-flowing under formation pressure into one of three 500 bbl frac tanks through a 4" line. Gauges on the tubing/casing annulus and bradenhead indicated 0 psi. Although tubing pressure could not be acquired at the time of the inspection, inspection reports from 9/15 - 9/22 indicate the well was back-flowed when frac tank storage was available and shut-in when unavailable. Tubing pressure recorded during and at the end of the longest shut-in period of 49 hours indicate injection formation pressures reached approximately 380 psi. at the surface.

The base of useable quality water was determined to be at 300' subsurface by the Texas Commission on Environmental Quality. Inspections on September 12, 2003, indicate that two inactive wells, approximately .43 and .21 miles from the injection well were found producing fluids to the surface. The spills appeared to be caught rather quickly as evidenced by relatively small kill zones. A third well, an active producer, also .43 miles from the producer, was discovered to be exhibiting pressure increases at its bradenhead. Injection was ceased and back flow was initiated on September 15, 2003. At the time of inspection, one well had been plugged with subsurface capping, burial and site remediation yet to be completed. Rigs were working to plug and abandon the second inactive well and to squeeze cement from the existing top of cement to surface along the long string casing of the active producer .

This incident provides evidence that pressure influences can exceed the 1/4 (.25) mile limitation that the RRC holds to in their current AOR policy. The extended pressure influence demonstrates a need for consistent use of accepted engineering models to evaluate reservoir capacity and, where warranted, to condition the permit to restrict pressure influence to that area covered by corrective action. In this case, it is also noted that one well within the 1/4 mile AOR conducted by the RRC but not on record, escaped scrutiny. When considering AORs of questionable completeness, the RRC should consider a worst case scenario well to condition its permits. The Region will continue to follow the developments of this injection facility which is currently under RRC review for continued injection.

Subsection 5.3 BSLR Operating, Ltd., Project No. F 14563, Caldwell, J. H. Lease (11490), Well Nos. 1, 3, 4, 5, 6, 8 and 10, Brazoria County

The BSLR facility is permitted to inject fluid into a reservoir productive of oil and gas on a commercial basis. The permits specify the fluids eligible for injection. Each well is eligible to inject 6000 - 7000 bbls per day of salt water. In January 2003, during an offloading of fluids slated for injection from tanker trucks, an explosion occurred causing death and injury to workers. Subsequent investigation by state and federal authorities led to the belief the explosion was due to ignition of fumes from the fluids offloaded. Region 6 Criminal Investigation Division (CID) has the lead in EPA for investigating this event. The Source Water Protection Branch has provided CID with the documentation collected through a subsequent file review.

Subsection 5.4 Basic Energy, Project No. F15516, Hall, A F. Lease (04049), Well No 1D, Panola County

The Basic Energy facility is permitted to inject fluid into a reservoir productive of oil and gas on a commercial basis. Starting initially in 2001, there has been an ongoing effort by the RRC to resolve complaints by a small rural community in the vicinity of the facility. Several communications have occurred over the past year between Region 6, the RRC and the community's leader centering on the community's fear that the facility has caused significant contamination to their drinking water sources and ecological system. Past sampling events, shared between the RRC and the community, have revealed no conclusive evidence of the type of contamination that might potentially be associated with a commercial Class II injection well facility. In the most recent round of sampling, the RRC sampled seven potential water sources in October of 2003. Analyses revealed significant, potentially related, contaminants in several of the samples, prompting a letter by the Commission cautioning residents not to use the water for domestic purposes. The community's leader, Mr. David Hudson, has stated that all persons rely on other water supplies at this time. The RRC is currently evaluating the results of the last sampling event to determine their next course of action.

Subsection 5.5 Amendment to RRC Rules affecting the implementation of the UIC program.

Last year the RRC proposed amendment to 16 T. A. C. Section 3.14, Rule 14. Rule 14 sets forth the RRC's requirements for plugging and abandonment. The amendments provide a mechanism for approval of alternative plugging materials. The RRC reports that any requests for plugging an injection well with alternative materials will be reviewed on a case-by-case basis by executive staff and will only be approved where the alternative materials can provide equal protection to usable quality water. The Region considers this amendment a possible modification to the approved program and accepts the RRC offer to report any use of alternative materials in plugging wells.

Section 6 Special Funding Projects

Subsection 6.1 Radioactive Survey Instruments

As a result of new legislation, Senate Bill 1338, the RRC received new responsibilities over equipment contaminated with naturally occurring radioactive materials (NORM). The RRC has amended their Rule 94 to require operators to identify equipment contaminated by NORM within 5 years and to identify NORM at commercial Class II facilities within 2 years. In 2003 the RRC applied to EPA for funds to purchase the survey instruments necessary to ensure compliance. On September 11, 2002 the RRC was awarded $18,700 of FY 02 funds to purchase 20 radiation survey instruments. Inspectors use the instruments to verify compliance with new requirements for operators to identify and tag equipment contaminated with NORM at injection and disposal facilities.

Subsection 6.2 Ongoing Imaging Project

The Oil and Gas Division received an award of $40,000 on September 26, 2000, to initiate a digital imaging project. During FY2001, a digital imaging workstation, document scanner, and high-speed log scanner were purchased and installed in the RRC's Central Records. In addition, the RRC moved one permanent employee from ES to Central Records to operate the station. All reasonably sized documents associated with permit applications received since September 2000 are in digital format and accessible on the web. In FY2003 the RRC continues to progress in electronically imaging and indexing UIC documents. All new pressure test report forms (Form H-5) are scanned and indexed. Since 2001 the RRC has been working to scan nearly 10 years of H-5 forms. Currently UIC staff have completed scanning and indexing Form H-5s received in 1993 and most of 1994.

Section 7 Recommendations

Subsection 7.1 Delinquent Reporting / Non Reporting

The RRC continues to struggle with operator compliance with reporting requirements; most notably, the non-reporting of witnessed MITs and the delinquent reporting of the annual operator reports, Form H-10. The RRC has historically relied on NOVs to raise compliance. EPA recommends the RRC consider an increasing fee schedule for delinquent reports to offset the administrative costs incurred in the NOV process.

Subsection 7.2 Inspections

The effort put forth by the RRC inspecting injection wells is significant and EPA recognizes the increased focus on witnessing MITs. However, Chart 3.3 reflects a 4-year trend of fewer inspections overall, and cautions this trend not be allowed to continue.

Subsection 7.3 Permitting

This Region's largest concern with UIC is with over-pressurization of existing injection formations. Chart 3.8 reflects an extraordinary increase in permit modifications, brought about mainly through the RRC's excellent compliance review effort. Further, we believe the need for permit modification is indicative of insufficient existing permit conditions, including injection rates and/or pressures. Increasing those parameters without adequate consideration of existing conditions in the receiving formations can bring endangerment to USDWS. The incident involving surface breakouts, described in Subsection 5.2, provides a clear example of insufficient consideration of the receiving formation pressures. This Region recommends the RRC consider a policy change with regard to the extent and manner receiving formation pressure is considered in all permit issuances and modifications.